ELSEVIER
Available online at www.sciencedirect.com
ScienceDirect
Energy Procedia 4 (2011) 2150–2156
Energy Procedia
www.elsevier.com/locate/procedia

GHGT-10

Implementation of horizontal well CBM/ECBM technology and the assessment of effective CO_2 storage capacity in a Scottish coalfield

Caglar Sinayuc, Ji-Quan Shi[*], Claire E. Imrie, S. Amer Syed, Anna Korre, Sevket Durucan

Department of Earth Science and Engineering, Royal School of Mines, Imperial College London, Prince Consort Road, SW7 2BP, UK

Abstract

In this study the theoretical and effective methane recovery and CO_2 storage potential of four coal seams within a well characterised section of a CBM license in Scotland are estimated, considering different horizontal well patterns, the effect of permeability heterogeneity and the composition of the injected fluid. The study concerns the Airth area of the Clackmannan coalfield in the Scottish Midland Valley. The effort on building the static earth model and the history match results of the pre-existing vertical and newly drilled horizontal wells is briefly described. Initial simulations of the horizontal well primary methane production and CO_2/flue gas enhanced recovery enabled the length, configuration and alignment of the horizontal wells to be optimised for the long-term simulations. This configuration was then used to estimate the Effective Capacity of a selected area within the Airth field for CBM, ECBM and CO_2 storage. To evaluate the impact of permeability heterogeneity and uncertainty on reservoir performance and Effective Capacity for methane recovery and CO_2 storage, multiple realisations of possible permeability distributions across the selected area were geostatistically generated. Initially, primary production runs were performed using 100 permeability distributions with a median value of around 1 mD. A number of realisations with different median permeabilities were then selected and used for flue gas (13 % CO_2/87 % N_2) and mixed gas (50 % CO_2/50 % N_2) enhanced CBM recovery and CO_2 storage runs.

Keywords: ECBM recovery; CO_2 storage; horizontal well; storage capacity

1. Introduction

Successful CO_2 enhanced coalbed methane (ECBM) recovery could have a significant impact on the economics of a coalbed methane gas field, with the added environmental benefits arising from the permanent storage of CO_2 in the coal seams. The main barrier to the extensive implementation of coalbed methane (CBM) technology worldwide has been the relatively low permeabilities of most coal seams. Furthermore, matrix swelling due to pure CO_2 injection for CO_2-ECBM and carbon dioxide storage in coalbeds reduces coal permeability, well injectivity and therefore storage capacity significantly. From a methane production point of view, N_2 injection has so far proved to be more effective than CO_2 injection for enhancing methane recovery, without any adverse effect on permeability. Injecting flue gas or CO_2 enriched flue gas could take advantage of this phenomenon and ensure that injectivity is not lost. The development of new technologies, particularly in the area of horizontal drilling, can radically change the commerciality of ECBM and CO_2 storage. One of the principal benefits of horizontal well technology is that the direction of the borehole can be controlled with respect to the principal permeability direction (face cleat) of the coal seam and achieve a much greater exposure of coal than a vertical well.

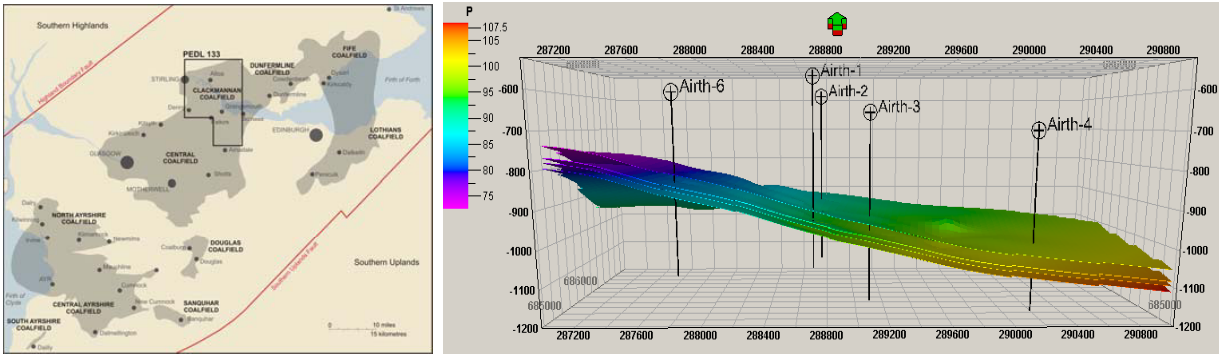
In recent years, Composite Energy Ltd. has successfully demonstrated horizontal well drilling for CBM/ECBM in a Scottish coalfield. In a project jointly funded by Composite Energy Ltd., BG Group, Scottish Power and the Royal Bank of Scotland, the team at Imperial College have carried out research investigating the potential for combined use of horizontal wells and flue gas (or CO_2 enriched flue gas) injection in order to overcome the well injectivity barrier experienced in vertical wells, thus aiming at improving methane recovery and CO_2 storage capacity. The main research effort focused on the Airth area, within the Clackmannan coalfield of the Scottish Midland Valley, where most CBM drilling has taken place (Figure 1a).

[*] Corresponding author. Tel.: +44-20-7594-7374; fax: +44-20-7594-7354.
E-mail address: j.q.shi@imperial.ac.uk

doi:10.1016/j.egypro.2011.02.100

The first vertical CBM well in the area (Airth #1) was drilled by Coalbed Methane Ltd. in 1993, followed by three more vertical wells Airth #2, #3 and #4 drilled during 1994-97. Since 2004, drilling operations have been continued by Composite Energy Ltd. Two vertical wells (Airth #5 and #6) were drilled in 2005, with extensive reservoir characterisation work performed on both wells by Ticora Geosciences Inc. [1]. Faced with relatively low reservoir permeabilities and gas flow rates, Composite Energy Ltd. drilled six multi-lateral horizontal wells (Airth #5Z, #7, #8, #9, #10 and #11) in the same area. These horizontal wells utilised the existing vertical wells, with the multi-laterals following four different seams targeted for CBM and ECBM.

In addition to gas and water production data provided from these horizontal wells, data from a large number of exploration wells drilled by British Coal and Scottish Coal, as well as seismic data obtained by the industry and BGS, were available to the project. Ticora Geosciences Inc. had already measured and reported the methane sorption isotherms for the target coal seams. The project described here determined the N_2 and CO_2 isotherms, the swelling coefficients for methane, CO_2, N_2 and flue gas, and the mechanical and elastic properties of the target seams through an experimental programme to support the numerical modelling work which followed. This paper presents the results obtained for one of the target seams in detail as well as referring to the total capacities estimated for the four seams within the selected area.



(a) (b)

Figure 1. (a) Map of Scottish coalfields and the location of the larger CBM license which includes the Airth area studied [1]; (b) the static earth model of the studied section, illustrating the reservoir structure, the four target coal seams, the inter-bedding and the vertical CBM wells considered in building the model (depths in metres, 2x image exaggeration).

2. The static earth model and initial reservoir simulations

The study region covers a surface area of approximately 12 square kilometres, bounded by two main faults in the North and South. The coal seams targeted will be referred to as Seams A, B, C and D, and most of the discussions in this paper will focus on Seam A. The static earth model was prepared in Schlumberger's Petrel software [2], using the geological data and the vertical and horizontal CBM well profiles provided by Composite Energy Ltd. The depth contours of Seam A, 17 known coordinates along the horizontal CBM wells and six other boreholes taken from a coal exploration database formed the basis for constructing a surface horizon to represent the base of Seam A. A further 48 data points were defined along the horizontal CBM wells using the depth contours of the same seam in order to reflect the regional stratigraphy with accuracy in the static geological model. Using Seam A base horizon as reference, the base and top surface horizons of all four coal seams were defined using the thickness and depth of the seams indicated by the vertical CBM wells and exploration boreholes in the study area. The main static earth model consists of the four target seams, which were assumed to be continuous laterally (Figure 1b).

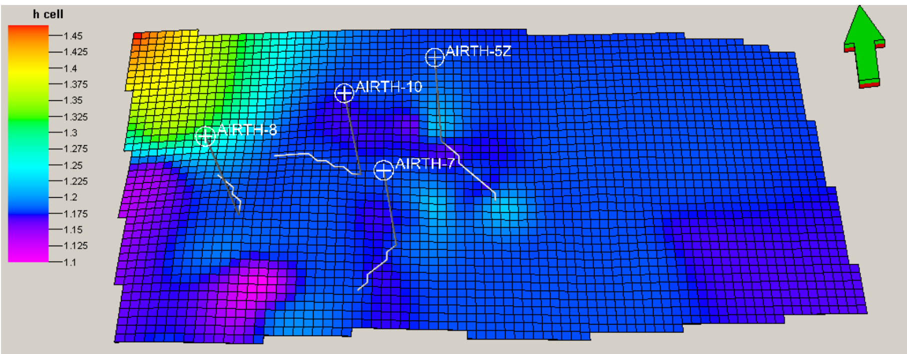


Figure 2. The Airth field study area, Seam A surface horizon and the horizontal wells modelled (seam thickness in metres).

In an attempt to gain a better understanding of the reservoir characteristics, the historical gas and water productions from the pre-existing vertical wells Airth #1, #2, #3 and #4 were analysed and history matched. As the Airth field production data from the newly drilled horizontal wells Airth #7, #8, #10 and #11 (Figure 2) became available, history matching of the limited horizontal well production data available was also carried out. During history matching, the field gas rates were used as input to the simulator; the outputs were water production rates and bottomhole pressure (BHP). A reasonable match to the field water rates was obtained using 1 mD permeability for both Airth #10 and Airth #7 horizontal wells. The history matching results indicated that the seams were capable of producing the recorded gas rates even at a lower permeability of 0.1 mD, albeit requiring a lower BHP. History matching of the field production data for 3 vertical wells (Airth #1, #2 and #3) over the time period February 1994 to October 2001 suggested that a permeability of 1 mD is adequate for sustaining gas rates at Airth #1. Much higher permeabilities of ~10 mD and ~5 mD were required for Airth #2 and Airth #3 respectively, which may be due to more effective hydraulic fracturing at these two wells.

3. Target seam Langmuir parameters and swelling coefficients

The Imperial College ECBM simulator METSIM2 [3], which accounts for dynamic permeability changes due to stress and pore pressure effects during primary methane production and CO_2 or mixed gas injection, was used for the reservoir simulations throughout. As well as the mechanical and elastic properties of the coals in question, the swelling coefficients and sorption isotherms for CH_4, CO_2 and N_2 are required as input to the permeability model to estimate the dynamic permeability changes during simulation of primary and enhanced CBM recovery and CO_2 storage. The methane isotherm for Seam A has been previously measured by Ticora Geosciences Inc. and was made available to the project by Composite Energy Ltd. Sorption isotherms for CO_2 and N_2, on the other hand, needed to be estimated. In order to determine the swelling coefficient for Seam A, laboratory measurements of swelling strains for CH_4, CO_2 and N_2 were conducted at Imperial College on samples taken from the Airth #11 horizontal well. The CH_4 swelling strain data and the CH_4 sorption isotherm were used to determine the Seam A swelling coefficient for CH_4. Assuming that the swelling coefficient is the same for the three gases, the Seam A sorption isotherms for CO_2 and N_2 were estimated using the swelling strain measurements obtained for the two gases in the laboratory. The obtained Langmuir isotherms for Seam A are presented in Figure 3, with the corresponding Langmuir parameters and swelling coefficients listed in Table 1. It was also noted that the dry ash free CH_4 sorption isotherms reported for Seams B, C and D were very close to that reported for Seam A [1]. Therefore, and in the absence of any coal samples to carry out swelling strain measurements for these seams, it was assumed that the same parameters determined for Seam A can be used as the starting point for Seams B, C and D, and their sorption isotherms determined by accounting for their respective *in situ* ash and moisture contents.

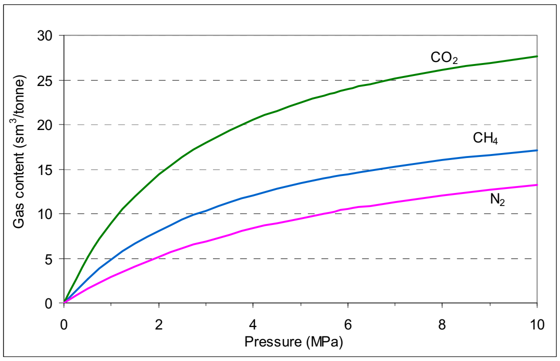


Figure 3. Measured CH_4 and estimated (N_2 and CO_2) Langmuir isotherms for Seam A (d.a.f).

Table 1. The Langmuir parameters and swelling coefficient obtained for Seam A.

Parameter	N_2	CH_4	CO_2
P_L, MPa	6.4	3.86	3.0
V_L (d.a.f), sm^3/tonne	21.7	23.72	35.9
α_S (in situ), m^3/sm^3	3.4×10^{-4}	3.4×10^{-4}	3.4×10^{-4}

4. Theoretical maximum recoverable gas and CO_2 storage capacity estimates

The theoretical gas-in-place (GIP) values depend on the initial adsorbed gas concentration, reservoir pressure, coal thickness, ash and moisture content and coal density, as well as the free gas in the cleats. During primary and enhanced coalbed methane production, the reservoir pressure is reduced to a certain level, which is referred to as the abandonment pressure. At abandonment pressure, coal still holds a given volume of methane, which can be referred to as the unrecoverable GIP. *In situ* gas content data suggested that at hydrostatic pressure the seams were close to saturated. Assuming initial reservoir pressure as hydrostatic, a 0.28 MPa (40 psi) abandonment pressure, and using the adsorption isotherms presented in Figure 3, the recoverable GIP for Seam A within the study area was calculated as 160 million sm^3, which is 9% lower than the initial GIP (176 million sm^3). In the same manner, the total recoverable gas for the four target seams in the study area was calculated as 610 million sm^3, 91% of the initial GIP.

The theoretical carbon dioxide storage capacity of a coal seam depends on the same parameters listed for theoretical GIP but, instead of adsorbed methane concentration, the CO_2 adsorption capacity of the coal at the initial reservoir pressure is referred to.

The theoretical CO_2 storage capacity for Seam A was calculated as 565×10^3 tonnes. However, injection of typical power plant flue gas (13% CO_2/87% N_2) and its CO_2 enriched variant (50% CO_2/50% N_2) reduces the theoretical CO_2 storage capacities of Seam A to 112×10^3 tonnes and 352×10^3 tonnes respectively. The calculated theoretical recoverable GIP values and the CO_2 storage capacities for Seam A and the total values for the target seams in the study area are presented in Table 2.

Table 2. Theoretical maximum recoverable gas-in-place and CO_2 storage capacity estimates.

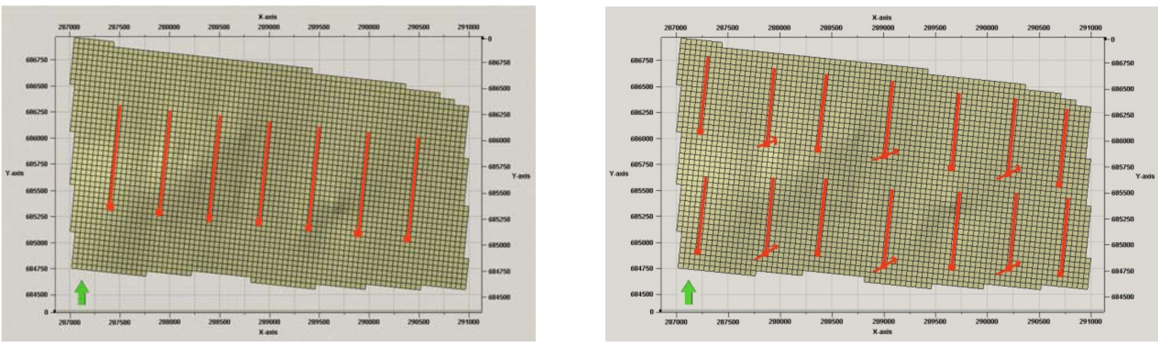
	Theoretical GIP, million sm^3	Recoverable GIP, million sm^3	CO_2 storage capacity, ×10^3 tonnes		
			Pure CO_2	Flue gas	Mixed gas (50% CO_2/50% N_2)
Seam A	176	160	565	112	352
Total for four seams	673	610	2,163	427	1,345

5. Estimation of the effective methane recovery and CO_2 storage capacities

The effective capacity estimations were carried out considering the impact of different horizontal well patterns and reservoir heterogeneities on gas production and storage rates. Uniform permeability across the study area in the Airth field, with a base case permeability of 1 mD, was used in the initial simulations. The impact of permeability levels on the reservoir performance was then considered. The performance of two different ECBM schemes, involving injection of typical power plant flue gas (13% CO_2/ 87% N_2) and its CO_2 enriched variant (50% CO_2/ 50% N_2), were studied.

5.1. Effect of well pattern on effective methane recovery

Two different horizontal well patterns, consisting of 7 and 14 horizontal wells distributed across the Airth model domain, have been considered for primary methane recovery over a 10 year production period. The wells are approximately North-South oriented to place them normal to the face cleats (Figure 4). The results show that the use of a 14-well pattern could lift the recovery factor from around 35-40% to over 50%. The methane production was found to be relatively insensitive to permeability anisotropy. For example, a five-fold reduction in the butt cleat permeability to 0.2 mD (i.e. a face cleat/butt cleat permeability ratio of 5) would yield a recovery factor of 49.9%, compared with 53.8% for the isotropic permeability base case. Table 3 presents the simulation results for Seam A, and the total for the four target seams in the study area.



(a) (b)

Figure 4. The 7 and 14 horizontal well patterns: (a) the 7-well pattern: well length = 1000 m; well spacing = 750 m; (b) the 14-well pattern: well length = 750 m; well spacing = 450 - 600 m.

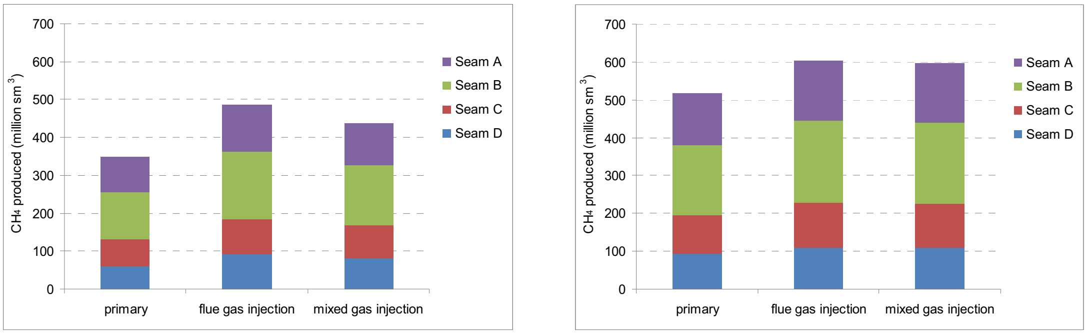
Table 3. Simulated cumulative primary methane production for Seam A and the four target seams over a 10 year period.

	Gas-in-place, 10^6 sm^3 (% of total)	Cumulative production, million sm^3		Recovery factor	
		7-well	14-well	7-well	14-well
Seam A	176	62.4	94.7	35.3%	53.8%
Total for four seams	673	231.0	350.0	34.3%	52.0%

5.2. Effect of different injection gas compositions on effective methane recovery and CO_2 storage capacities

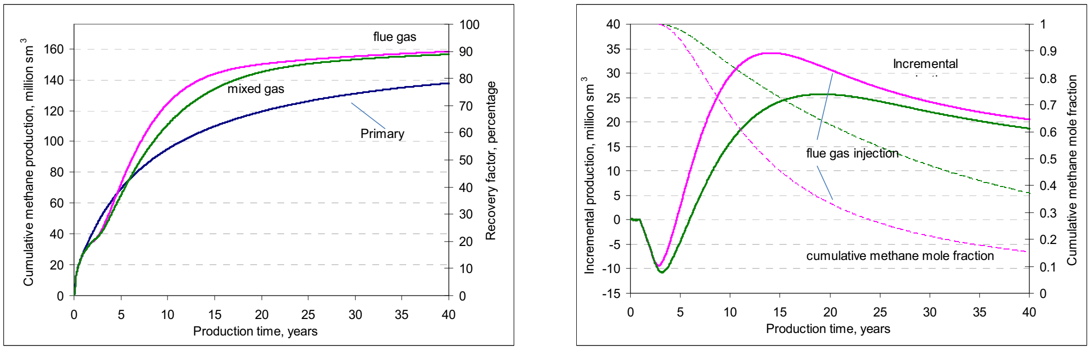
The above results suggest that, over 10 years, primary production is capable of recovering just over 50% of the gas-in-place using a 14-horizontal well pattern. Different enhanced methane recovery schemes involving injection of power plant flue gas and its CO_2 enriched variant have been explored to optimise methane recovery and also CO_2 storage volume. Simulations with a 14-horizontal well pattern were carried out for 10 and 40 year periods with injection starting after one year of primary production. During simulations of enhanced recovery, every other well in each row (6 wells in total) was converted to an injection well as illustrated in Figure 4b. The bottomhole injection pressure was set at 1.5 times the initial reservoir pressure.

It was observed that, over a 10 year period, the overall methane recovery for the four seams can be markedly increased by the injection of flue gas, e.g. up to 72.5% from 52% for the 14-well pattern case. In comparison, this positive effect in methane recovery is less pronounced with mixed gas injection (65.2%) as can be seen in Figure 5a. After 40 years of production, the primary production recovery factor reaches 78% and nearly 90% of the theoretical gas-in-place can be recovered by ECBM (Figures 5b and 6a). However, the production enhancement due to flue gas and/or mixed gas injection slows down after 15 years. There is a trade-off between incremental methane recovery and produced gas quality, as shown in Figure 6(b) for Seam A.



(a) (b)

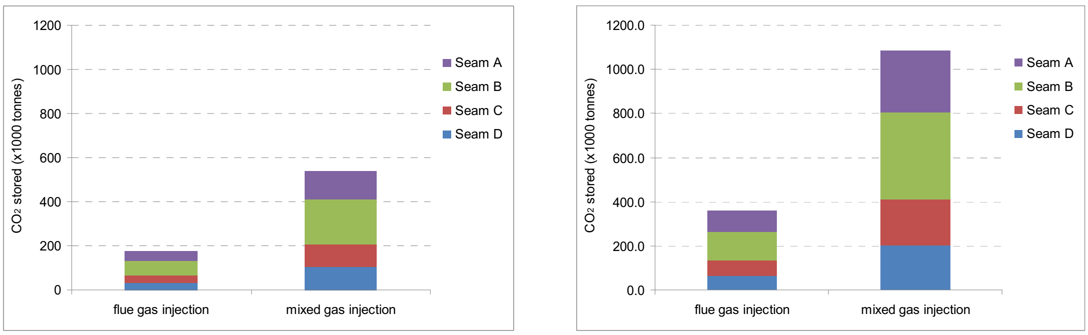
Figure 5. Breakdown of cumulative methane production per coal seam for primary and enhanced recovery (a) after 10 years and (b) after 40 years of CBM/ECBM production (14-well pattern).



(a) (b)

Figure 6. Primary and enhanced methane recovery results for Seam A over 40 years of simulation: (a) cumulative methane production; (b) cross-plot between incremental methane recovery and methane fraction in the produced gas (14-well pattern).

Figure 7 illustrates that mixed gas injection is much more efficient for CO_2 storage as well as maintaining a higher molar fraction methane in the produced gas (Figure 6b). In 10 years, up to 539,000 tonnes of CO_2 may be stored in the four seams with mixed gas injection using a 14-well pattern, which is three times as much as that stored with flue gas injection (Figure 7a). Over a 40 year period the stored CO_2 quantities double, reaching 1,083,000 and 357,000 tonnes respectively (Figure 7b).



(a) (b)

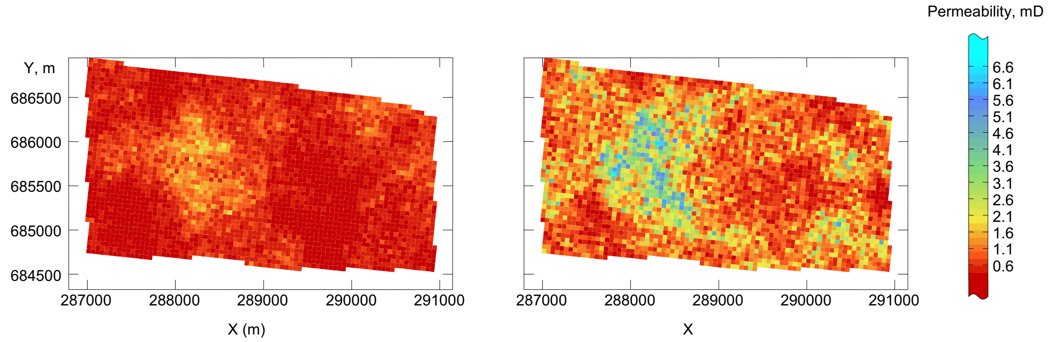
Figure 7. Breakdown of cumulative CO_2 storage per coal seam for flue gas and mixed gas injection (a) after 10 years and (b) after 40 years of ECBM production (14-well pattern).

5.3. Effect of reservoir heterogeneities on effective methane recovery and CO_2 storage capacities

The history matching effort of the historical gas production suggested that the permeability of the Airth field is likely to be heterogeneous. To evaluate the impact of reservoir heterogeneity on methane production and CO_2 storage capacities, multiple realisations of possible permeability distribution across the study area were geostatistically generated. Initially, primary production runs were performed using 100 permeability distributions with a median value of around 1 mD. Three realisations with different median permeabilities were then selected and used for flue gas (13% CO_2/ 87% N_2) and mixed gas (50% CO_2/ 50% N_2) enhanced CBM recovery runs.

The permeabilities were assumed to range between around 0.2 and 5 mD with median values of around 0.5 to 1 mD. Ideally, it was thought that the simulations should honour the observations that higher permeabilities may occur in the region penetrated by Airth #10 horizontal well, flanked by lower permeabilities particularly in the far SW corner of the field. It is possible that the coal is more permeable in areas with higher relief due to increased fracturing. It was therefore decided that, in order to honour the indicated permeability distribution it would be necessary to condition the simulations. This was done by defining a relationship between the relief of the coal seam and exploiting this to define a general trend representing strain; and secondly by using a small set of fabricated data points to ensure the correct range of values, and anchor the permeabilities where required.

A convenient and robust method for producing conditional simulations is to first co-krig the permeability with a background variable representing strain (with a correlation coefficient of 0.3), then to use the resulting map as a local mean on which to generate simulations. The distribution of local mean permeability has a median value of 1.011 mD. Four similar maps with median permeabilities ranging between around 0.5 and 0.9 mD were also created. Sequential Gaussian Simulation was performed using these maps as the local mean, and specifying the variogram to have 50% nugget and 50% spherical function with a range of 500 m in accordance with the relief of the coal seam. For each permeability-range scenario, 100 simulations were generated. Examples of the resulting back-transformed simulations are shown in Figure 8 with median permeabilities of (a) 0.457, and (b) 1.037 mD respectively.



(a) (b)

Figure 8. Two examples of the permeability simulations: median permeability of (a) 0.457 mD and (b) 1.037 mD.

Initially, 100 simulations each with a different permeability distribution (with a median permeability close to 1 mD), were performed using the 14-horizontal well configuration. 40 further simulations using subsets of the additional permeability realisations that were generated with lower median permeabilities (with a minimum of 0.457 mD) gave rise to a wider range of primary methane recovery values (between 39.8% and 59.9%) for Seam A as presented in Table 4. Three permeability distributions, respectively representing a low permeability (40% primary recovery), a medium permeability (50% primary recovery) and a high permeability (60% primary recovery) case, were selected for enhanced recovery simulations with flue gas and mixed gas injection. The results obtained for Seam A in terms of methane recovery and volume of CO_2 stored are presented in Table 4. As expected, enhanced recovery with flue gas injection results in a greater increase than mixed gas injection, although the difference reduces with increasing permeability. Table 5 presents the upper and lower bounds of methane production and CO_2 storage effective capacity estimates for the four target seams over a 10 year simulation period.

Table 4. Reservoir performance for three permeability realisations with different median permeabilities (Seam A, over 10 years).

	Primary recovery factor	**ECBM recovery factor (incremental)**		**CO_2 stored, $\times 10^3$ tonnes (% of injected gas stored)**	
		Flue gas injection	**Mixed gas injection**	**Flue gas injection**	**Mixed gas injection**
Low permeability case	39.8%	43.6% (3.8%)	39.0% (-0.8%)	20.2 (97.1%)	68.0 (99.7%)
Medium permeability case	50.0%	64.2% (14.2%)	57.3% (7.3%)	36.0 (92.7%)	110.5 (98.5%)
High permeability case	59.9%	75.1% (15.2%)	70.0% (10.1%)	56.7 (73.6%)	163.4 (90.9%)

Table 5. Lower and upper bounds of methane recovery and CO_2 storage effective capacity over in the study area (10 year simulation period).

		Primary production, million sm^3	ECBM production, million sm^3		CO_2 stored, $\times 10^3$ tonnes	
			Flue gas injection	Mixed gas injection	Flue gas injection	Mixed gas injection
Seam A	Lower bound	70.0	76.7	68.6	20.2	68.0
	Upper bound	105.4	132.2	123.2	56.7	163.4
Seam B	Lower bound	96.6	105.9	94.7	27.9	93.9
	Upper bound	145.5	182.5	170.1	78.3	225.6
Seam C	Lower bound	51.7	56.7	50.7	14.9	50.2
	Upper bound	77.9	97.6	91.0	41.9	120.7
Seam D	Lower bound	49.3	54.0	48.3	14.2	47.9
	Upper bound	74.3	93.1	86.8	39.9	115.1
Total	Lower bound	268.0	293.0	262.0	77.0	260.0
	Upper bound	403.0	506.0	471.0	217.0	625.0

6. Conclusions

This paper presented a study on the determination of both theoretical and effective methane recovery and CO_2 storage capacities of coal seams in a 12 square kilometre area within the Airth field in Central Scotland. The effect of horizontal well layout, number of wells, injected fluid composition and permeability heterogeneity on capacity estimates was assessed. The initial history matching study carried out using the historical production data for the vertical wells provided the evidence that the coalbed reservoir permeability is in the order of 1 mD. The methane production and CO_2 storage potential of a selected coal seam, namely Seam A, is discussed in detail. Cumulative production rates and CO_2 storage capacities for the four target seams are also presented.

It is estimated that around 34% of volumetric recoverable gas-in-place could be produced over a 10 year period using a 7-horizontal well pattern, which is much lower than the 52% that would be produced with a 14-well pattern. The recovery factor could reach over 72% by injecting flue gas, with an additional storage of 176,000 tonnes of CO_2. Only after 40 years of primary production can the recovery factor exceed 77%, whereas flue gas injection for the same period would achieve nearly 90% recovery and 357,000 tonnes of CO_2 stored. It was observed that mixed gas injection (50% CO_2/ 50% N_2) was slightly less effective for enhanced methane recovery; however, compared to flue gas injection, this scheme tripled the CO_2 stored over 40 years.

To evaluate the impact of reservoir heterogeneity on methane production and CO_2 storage capacities, multiple realisations of possible permeability distribution across the study area were geostatistically generated. Primary production runs were performed using 100 permeability distributions with a median value of around 1 mD and enhanced recovery and CO_2 storage capacities for flue gas and mixed gas applications were estimated using three realisations with different median permeabilities. In the case of Seam A, the effective storage capacity of the seam ranged from 20,200 to 56,700 tonnes for flue gas injection and 68,000 to 163,400 tonnes for mixed gas injection over a 10 year simulation period. On the other hand, the total effective storage capacity for the four seams in the study area ranged from 77,000 to 217,000 tonnes for flue gas injection and 260,000 to 625,000 tonnes for mixed gas injection over a 10 year simulation period. It is estimated that the total effective storage capacity ranges would be doubled for both flue gas and mixed gas injection over a 40 year injection period.

Acknowledgements

The authors wish to thank Composite Energy Ltd., the BG Group, Scottish Power and the Royal Bank of Scotland for their funding and contributions towards the research reported in this paper.

References

[1] Composite Energy Ltd., 2006-09. Various internal reports. Sterling. Scotland.
[2] Schlumberger, 2009. Petrel seismic-to-simulation software. Version 2009.2 for Windows.
[3] Shi, J.Q., Durucan, S., 2005. A model for changes in coalbed permeability during primary and enhanced methane recovery. SPE Reserv. Eval. Eng. 8(4), 291-299.